

CBO PAPER

REFORMING THE FEDERAL ROYALTY PROGRAM FOR OIL AND GAS

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Abstract

The federal government collects royalties from businesses that hold leases to produce oil and gas on public lands. The petroleum industry has proposed several changes to the way the government manages the collection of those royalties. In addition, the government recently revised its rule for how some of the royalties are valued. Even if implemented fully, those various reforms would be unlikely to have much effect on the volume of oil and gas produced from federal leases both because the scope of the changes is small and because the level of U.S. oil and gas production is not particularly responsive to changes in prices and costs. As a result, it is likely that any gain to the petroleum industry from such reforms would simply reflect a loss of the same amount to the federal budget, and vice versa. Businesses that lease the rights to develop petroleum resources commonly pay their federal royalties as a share of the market value of the oil and gas—one-eighth for production from most onshore federal lands and one-sixth from most offshore lands. In 1998, leaseholders paid a total of \$3.3 billion in royalties for the right to remove federal oil and gas valued at \$22.6 billion. Federal oil and gas account for 26 percent and 34 percent, respectively, of national production. For royalty purposes, the value of such oil or gas is measured as if the product were sold at the lease site (the property described in the lease contract), even though the actual sale may call for delivery away from the lease site and for enhancements to the quality of the product. Those actions add to the product's value, but they also entail costs to the producers. Disputes often arise between lessees and the government about who should shoulder which costs and what the true value of the oil or gas is back at the lease site.

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PREFACE

When businesses remove oil and gas from public lands, they are required to pay royalties to the federal government. A number of legislative and regulatory proposals would change the way that the government manages the collection of those royalties. This Congressional Budget Office (CBO) paper—prepared at the request of the House Committee on Resources—reviews the federal royalty program, describes the major proposals for changing it, and examines some of the potential economic and budgetary impacts of those changes. In keeping with CBO’s mandate to provide objective, impartial analysis, this report makes no recommendations.

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SUMMARY

The federal government collects royalties from businesses that hold leases to produce oil and gas on public lands. The petroleum industry has proposed several changes to the way the government manages the collection of those royalties. In addition, the government recently revised its rule for how some of the royalties are valued. Even if implemented fully, those various reforms would be unlikely to have much effect on the volume of oil and gas produced from federal leases—both because the scope of the changes is small and because the level of U.S. oil and gas production is not particularly responsive to changes in prices and costs. As a result, it is likely that any gain to the petroleum industry from such reforms would simply reflect a loss of the same amount to the federal budget, and vice versa.

Businesses that lease the rights to develop petroleum resources commonly pay their federal royalties as a share of the market value of the oil and gas—one-eighth for production from most onshore federal lands and one-sixth from most offshore lands. In 1998, leaseholders paid a total of \$3.3 billion in royalties for the right to remove federal oil and gas valued at \$22.6 billion. Federal oil and gas account for 26 percent and 34 percent, respectively, of national production. For royalty purposes, the value of such oil or gas is measured as if the product were sold at the lease site (the property described in the lease contract), even though the actual sale may call for delivery away from the lease site and for enhancements to the quality of the product. Those actions add to the product's value, but they also entail costs to the producers. Disputes often arise between lessees and the government about who should shoulder which costs and what the true value of the oil or gas is back at the lease site.

PROPOSALS FOR CHANGE AND A NEW RULE

To resolve those disputes, the Administration and representatives of the petroleum industry have proposed various changes to the royalty program. The industry supports legislation that would make three types of changes, either separately or in combination. (The proposals are commonly presented not as alternatives but as parts of a broad option for reform.) The first proposal would require that the government collect most of its oil and gas royalties in kind. Rather than making monetary payments equal to a percentage of the value of the oil and gas extracted at a lease site, the lessee would turn over a percentage of the physical volume of that product. The Department of the Interior's Minerals Management Service (MMS)—which is responsible for determining the value of federal oil and gas, collecting royalties, and

disbursing a share of those royalties to the states where the production takes place—would then sell the royalty product on its own. The second proposal would limit the industry's liability for certain costs that it now pays for moving, treating, and marketing federal oil and gas. A third proposal would restrict the audits that the government performs to determine whether lessees have correctly calculated their royalty payments. The industry argues that such reforms as limiting the amount of time MMS had to conduct audits would reduce lessees' uncertainty about their payments.

For its part, the Administration recently implemented a rule change that alters the basis on which lessees must value oil production that is sold in non-arms-length transactions (that is, sold between affiliated businesses). The change shifts that basis from the local posted price of oil to a value indexed to published prices for short-term (or spot) oil sales in the region. To estimate value at the lease site, lessees may adjust the published price to account for any differences in location and quality between their federal oil and the oil traded in those spot sales. The rule change was published on March 15, 2000, to take effect in June (with a subsequent grace period through September 2000). The industry, in accordance with its long-standing opposition to the change, has filed a court challenge to the final rule.

The legislative proposals for reform that the industry supports and the government's new rule on oil valuation are closely related. The government's actions to revise its rule gave impetus to the industry's desire to change the royalty program. In addition, the status of the valuation rule has complicated efforts to estimate the federal cost of reform legislation.

THE PETROLEUM INDUSTRY'S VIEW

Several concerns are behind the industry's push for royalty reform. First, it believes that the current approach (even before the new valuation rule) sets too high a value for federal oil and gas and, hence, requires too high a royalty payment. Second, lessees are confronted with an expensive, time-consuming, and uncertain process of audits and revaluations. Third, in the many sales that do not occur at the lease site, lessees must bear the costs of moving, treating, and marketing federal oil and gas beyond that site. Lessees contend that the government should not include those costs—which enhance royalty value at the lease site—in the value on which royalty payments are based. One way in which the government could end up paying those costs on its royalty share would be if it took all of its royalties in kind and sold that product itself. (The government currently receives some oil in kind that it sells to eligible small refiners, but it requires the lessees to collect payments from the refiner and forward them to MMS.)

THE GOVERNMENT'S VIEW

The Minerals Management Service agrees with the industry that reducing uncertainty in the process of collecting royalties is desirable. It is pursuing procedural changes that it believes will reduce the industry's administrative burden. It is also studying the feasibility of collecting royalties in kind in more situations. However, the agency makes several arguments against a broad requirement to collect royalties in kind and other industry-supported reforms.

First, MMS believes that taking royalties in kind may not be cost-effective for many remote, low-volume leases (where the costs of putting together a marketable amount of product are high) and in uncompetitive circumstances (such as where pipeline owners set very high charges for transportation). Requiring in-kind collections in those locations would reduce the government's royalty receipts. Second, MMS disputes the industry's concerns that royalty payments are too high. Indeed, it believes that in some uncompetitive markets, the current system recovers too few royalties. Third, MMS believes that lessees should retain their current liability for the costs of placing federal oil and gas in a marketable condition and selling it. Accordingly, when lessees calculate their royalty payments, they generally may not deduct the costs of gathering oil and gas (moving it to a central accumulation point), of normal treatment to remove impurities, or of marketing—regardless of where those expenditures take place.

THE BUDGETARY COSTS OF ROYALTY REFORM

The Minerals Management Service and the petroleum industry have made widely disparate estimates of the budgetary costs of the changes described above. MMS predicts that the industry's proposals to require in-kind royalties and to shift certain costs to the government would lower federal revenues. The industry has predicted that, combined, those proposals would increase federal royalties. Government and industry estimates also differ on whether the government would realize an increase in price—and, hence, gross proceeds—if it sold royalty oil and gas on its own. (In the debate over royalty reform, that price increase is often referred to as “price uplift.”) A related area of disagreement is what additional program costs would be associated with collecting royalties in kind. In addition, MMS predicts that its new rule about the way that federal oil is valued will increase government revenues—a prediction that the petroleum industry disputes.

Assessing the budgetary costs of royalty reform is difficult because the language of specific proposals has been open to multiple interpretations and continues to change. For example, significant disagreement exists about what some of the activities mentioned in those proposals actually entail. Nevertheless, the key issues

that underlie the industry's claim that its reform would increase federal revenues are whether producers would respond to the changes by increasing their production and whether, with a shift to in-kind royalties, the government could handle oil and gas more efficiently and get higher prices than private producers do. Without greater production or prices, any dollar that lessees gained from reforms would reflect a dollar in losses to the federal government (and vice versa for gains to the government from the oil valuation rule).

The Congressional Budget Office (CBO) concludes that oil and gas production from federal lands would probably not increase as a result of the industry's proposals for reform. The reductions that might occur in producers' uncertainty about royalty payments (because of collecting royalties in kind and restricting government audits) and in producers' costs (because of shifting costs to the federal government) would be fairly limited. And in any event, U.S. production of oil and gas is not sensitive to small changes in prices or costs. In CBO's view, it also is unlikely that the government could receive a higher price for its royalty product or benefit from lower selling costs than lessees can, because it lacks a profit motive to do so and has little expertise in marketing oil and gas.

ISSUES IN ESTIMATING THE COST OF REFORM LEGISLATION

CBO would be required to estimate the federal cost of any legislation that changed the royalty program for oil and gas. This paper describes some of the information—about changes in royalty payments and program costs—that CBO would need to prepare such an estimate. A cost estimate would also reflect the projection of royalty receipts expected under current law (the baseline), the division of those receipts into mandatory and discretionary categories of the budget, and the timing of those flows within the “budget window” (the period of estimation).

This paper does not present an official cost estimate for any piece of legislation. Specific details of future proposals could significantly alter the story. For example, a requirement to collect royalties in kind on all leases could raise the costs of the royalty program without increasing receipts. But if the legislative proposal was narrower, requiring MMS to collect royalties in kind only on leases from which savings were likely, the estimate could indicate a smaller budgetary cost to the government or even a gain.

CHAPTER I

INTRODUCTION

One-quarter of the nation's crude oil production and one-third of its natural gas come from federal mineral leases. In recent years, oil and gas leases have generated federal revenues of between \$5 billion and \$6 billion a year, mainly in the form of royalties that leaseholders pay to the government as a percentage of the market value of the oil and gas they produce. Many lessees contend that they are paying more in royalties than they should and that the process of calculating and paying royalties can be simplified. Accordingly, the petroleum industry has supported various legislative proposals that would change the ways in which the government determines the value of oil and gas produced on federal lands and collects royalties. The Administration, for its part, has put forward a regulatory change, also aimed at simplifying the royalty program, that alters how lessees must determine the value of federal oil.

The legislative proposals encompass several types of reform. They could be enacted either together or separately, but they are commonly presented as parts of a broad option for reform. They include changes that would require the government to take its oil and gas royalties in kind, as a share of the physical product (rather than monetarily, as a share of the product's market value); allow leaseholders to deduct additional costs of moving, treating, or selling oil and gas when determining their royalties; and revise the government's program for auditing royalty payments.

The histories of those proposals and the Administration's new oil valuation rule have been closely linked. The industry's concerns about the rule—which will probably lead to increased royalty payments—have brought additional urgency to its calls for reform. At the same time, the prospect of the new rule has complicated discussions of the budgetary impact of legislative reforms.

THE CURRENT ROYALTY PROGRAM

For many years, the federal government made oil and gas resources available to developers under the terms of the Mining Law of 1872, which offered properties on a noncompetitive basis for flat, per-acre fees. The current federal royalty program originated in the Minerals Leasing Act of 1920.¹ Later, the Acquired Lands Act of 1947 extended the leasing authority of the 1920 act over lands in the public domain

1. For a brief review of that history, see Marc Humphries, *The Oil and Gas Leasing System on Federal Lands*, CRS Report for Congress 91-577 ENR (Congressional Research Service, July 10, 1991).

to include areas that the federal government acquired from states and individuals. The Outer Continental Shelf Lands Act of 1953 revised the oil and gas leasing program to make offshore leases available through competitive auctions. The most recent major changes to the program came with the Federal Onshore Oil and Gas Leasing Reform Act of 1987, which broadened the circumstances under which the government must offer leases on a competitive basis. Those basic laws establish procedures for leasing public lands to developers, collecting compensation from the developers in the form of initial payments and royalties on subsequent production, and disbursing the receipts to various government accounts and to the states.

How the Government Assigns Leases and Collects Royalties

Three federal agencies manage the development of oil and gas resources on most public lands. For federal onshore lands, the Bureau of Land Management (part of the Department of the Interior) and the Forest Service (part of the Department of Agriculture) are responsible for issuing leases to mineral rights and overseeing production operations. For the federal offshore region, the Interior Department's Minerals Management Service (MMS) is responsible for leasing and operations.² However, MMS takes care of collecting royalties for all three agencies and disbursing a share of the government's net receipts to the states in which the production occurs. (MMS also manages the collection of royalties from leases on Indian lands. But that program is separate from the program for federal lands, and the valuation standard for Indian leases differs from that for federal leases. This paper focuses only on issues related to the royalty program for federal leases.)

The government assigns most federal oil and gas leases through competitive auctions, in which businesses bid an up-front payment (known as a bonus) and agree to pay rents on undeveloped lands and royalties on any future production.³ After production begins, the lessees pay royalties based on the market value of their sales, as reported each month to the Minerals Management Service.

Federal lessees generally pay 12.5 percent (one-eighth) of the value of production from onshore leases and 16.7 percent (one-sixth) of the value from offshore leases as royalties. However, lower rates may apply for onshore production from marginally profitable fields and for offshore production from deep waters and certain

2. The federal offshore region generally begins three miles out to sea. Areas within three miles of the shore are considered state waters, to be leased by state governments. (No federal royalties are collected from those state leases.)

3. For some onshore regions that receive little interest from bidders, the government may issue leases in a noncompetitive process.

largely unexplored areas of the Atlantic coast.⁴ In some cases, the government may even waive royalties on oil and gas from low-output wells if market conditions warrant. In recent years, the royalties paid by lessees have averaged less than 10 percent of the value of oil from onshore leases and 15 percent of the value from offshore leases.

Most royalty payments are made for oil and gas that the leaseholders sell on their own. But a small amount (about 5 percent in 1998) comes from oil and gas that the government collects as in-kind royalties and sells to eligible small refiners or through several small pilot projects. In the MMS small-refiner program, however, the lessee acts as the government's collector, taking the payment from the refiner and passing it on to MMS. Problems with that program (in particular, the difficulties of matching the volumes that the refiners take and the royalties that the lessees pay) have prompted MMS to investigate alternative systems for in-kind sales (see Box 1).⁵

Why the Government Collects Lease Bonuses and Royalties

The government collects bonuses and production royalties to compensate the general public for the market value of the resources that businesses remove from public lands. It disburses a share of those receipts to the states to help state and local governments meet their costs of supporting development activities on public lands.

Seeking compensation in those forms is not a necessary part of land development. The two-tier program of bonuses and royalties for federal oil and gas is just one of a number of ways in which the government makes public lands available and seeks compensation. For lands in which the government retains ownership, various laws establish different types of leasing and compensation systems for broad categories of mineral deposits (including onshore and offshore oil and gas, coal, geothermal resources, and so-called locatable minerals, such as gold and silver) as well as nonmineral resources (including timber and grazing lands). The federal government also promotes development by transferring ownership of public lands altogether (through such methods as the "patenting" of mining lands and, in earlier years, homesteading).

Offering federal oil and gas leases through competitive bidding helps to maximize public compensation. It also promotes efficient development of the resources, in the narrow sense that the businesses that get the leases (bid the highest bonuses)

4. For a discussion, see Congressional Budget Office, *Waiving Royalties for Producers of Oil and Gas from Deep Waters*, CBO Memorandum (May 1994).

5. A description of those problems appears in Department of the Interior, Minerals Management Service, Office of Policy and Management Improvement, *1997 Royalty in Kind Feasibility Study* (August 1997).

BOX 1.
A HISTORY OF TAKING FEDERAL ROYALTIES IN KIND

The government is allowed to collect oil and gas royalties either in cash, as a share of the market value of the production from federal lands, or in kind, as a share of the volume of production from federal lands. The legislative authority for taking royalties in kind comes from the Minerals Leasing Act of 1920 (for onshore resources) and the Outer Continental Shelf Lands Act of 1953 (for offshore resources). Amendments to the Energy Policy and Conservation Act also allow the President to use in-kind royalty oil (or other oil that has been traded for royalty oil) to fill the Strategic Petroleum Reserve.

The Minerals Management Service (MMS) established its program to sell royalty oil to small refiners in 1976. From that date through 1998, eligible small refiners purchased more than 430 million barrels of royalty oil, valued at over \$7.3 billion.¹ Under the original program, federal lessees billed the small refiners for daily volumes of oil, consistent with federal rules for determining royalty value and marketable production. In 1997, MMS concluded that it could generate additional revenues and reduce management costs for the government, lessees, and refiners by revising the royalty-in-kind program to more clearly establish the sales price and volume in the sales contract. Contracts with onshore producers were allowed to run out (from a high of 2.2 million barrels in 1996, sales of onshore federal oil slumped to less than 200,000 barrels in 1998).

Starting in 1997, MMS launched three pilot programs to investigate the feasibility of establishing open bidding for in-kind royalties, including royalty gas. The programs included crude oil sales in Wyoming from federal and state leases, natural gas sales in the so-called 8(g) zone of the Gulf of Mexico (an area where the federal government and coastal states share lease revenues), and natural gas sales in the rest of the Gulf of Mexico. The total volumes to be offered in those pilot programs are relatively small.

One of the largest dispositions of in-kind royalties (approaching the highest annual sales under the small-refiner program) has been the 28 million barrels of oil from the Gulf of Mexico that the Department of Energy (DOE) planned to divert to the Strategic Petroleum Reserve under a 1999 agreement between the Secretaries of Energy and the Interior. DOE initiated an exchange of offshore royalty oil for a mix of oils that would meet the nation's strategic needs. The diversion was intended to replace oil that the Congress had directed DOE to sell for budgetary reasons in 1996 and 1997 and to help satisfy a policy goal of aiding U.S. producers by taking crude oil off the market during a period of depressed prices. The acquisition of royalty oil was suspended in 2000, however, as government concern shifted to stemming high oil prices and DOE announced a drawdown of the petroleum reserve.

1. See Department of the Interior, Minerals Management Service, *Mineral Revenues 1998*, Table 36.

are those that expect to have the lowest costs of finding and producing the oil and gas.⁶ Low-cost producers are also likely to produce the most oil and gas in the future and thus pay the most royalties.

The two-tier program of bonuses and royalties also affects public compensation and the cost of development by allocating market risks between the lessees and the government. With a zero royalty rate, businesses would incur all of the risks of adverse changes in future production levels or prices; as the royalty rate increases, a growing share of those risks falls on the government. Businesses generally like to accept some risk if they believe it will increase their expected return. And economists generally believe that businesses make better decisions when their own resources are at stake and, hence, they can have lower costs. However, the government has also been willing to accept some risk in exchange for increased public compensation. By charging royalties, the government—which is often at a disadvantage relative to some producers in knowing what the true resource potential of a lease is—can protect itself against bidding that systematically undervalues public lands.

How Royalty Payments Are Calculated

Federal lessees calculate their royalty payments as their proceeds from the sale of oil and gas, minus certain costs that the government allows them to deduct, times the applicable royalty rate. The calculation is not straightforward, however, because of the difficulty of estimating sales proceeds and deductible costs. Sales proceeds reflect the marketable volume of production from the lease site and the unit market value of the product (the value per barrel of oil or cubic foot of natural gas). Under current regulations, marketable product is oil and gas that is sufficiently free from impurities to be acceptable to a typical buyer in that region. Market value reflects the price that a competitive market would establish for the product. That value depends on the location of the market (the point of sale) and the quality of the product at the time of sale. The value may differ from the sales price, depending on the competitive relationship between the buyer and the seller.

Imputing a Market Value at the Lease Site. The terms of the federal lease say that the location for valuing the product should be the lease site. However, under current regulations, the lessee has a “duty to market” the government’s royalty share. (Although in most cases, lessees pay their royalties in money rather than oil and gas, they tend to think of the royalty system as meaning that a certain percentage of the product belongs to the government. They refer to that product as the government’s

6. In a broader economic sense, efficiency refers to the production of oil and gas at the lowest social cost. Social costs could exceed lessees’ direct costs if production from federal lands caused environmental damage, precluded competing uses of the land that would have a higher value, or drew economic resources away from otherwise lower-cost production on nonfederal lands.

royalty share.) The lessee must bring that product up to a minimum marketable quality, get it to the delivery point, and pay all of the costs entailed therein. The location for valuing the product is the first point at which the product has been metered (its volume measured) and placed in a condition that makes it available for delivery to new owners (so that the product is marketable). For a significant volume of federal oil and gas, that metering and treating occur at a central accumulation point that is off the lease site (most commonly at a regional hub for one of the nation's oil and gas pipeline systems). The lessees must pay any costs of moving the product to that site.

Sometimes, lessees will sell part of their oil or gas from the lease site and part from the central accumulation point. In general, the market value of the product increases as the point of sale moves away from the production site and toward the place where the fuel will ultimately be consumed—petroleum refining centers for oil, large cities for gas. The value can also increase as the lessee expends additional effort to remove impurities or separate a stream of product into valuable coproducts—in particular, by processing natural gas to remove marketable gas liquids such as propane and butane.

In calculating royalties, regulations allow lessees to deduct certain costs from their sales proceeds for moving oil and gas beyond the lease site (or central accumulation point) and for processing before determining their payments. The lessees are in effect calculating federal royalties on the basis of the proceeds they would have received had the sale taken place back at the lease site (or central accumulation point) and before processing.

Imputing a Market Value for Arms-Length and Non-Arms-Length Sales. To ensure that the sales prices reported by lessees reflect a competitive market value, current regulations also consider the relationship between the market participants.

If the buyer and seller have competing interests—that is, the sale is an arms-length transaction—and the transfer of ownership takes place at the lease site (or central accumulation point), MMS considers the market value to be the actual sales price. For crude oil, the actual price is often the posted price for the oil field (see Box 2). For an arms-length sale that takes place elsewhere, regulations provide two options for calculating royalty payments. One is based on an actual price for a reported competitive transaction in a nearby oil or gas field. The other estimates the value back at the lease site by deducting from the actual sales price the costs of moving the product from the lease site (or central accumulation facility) to the point of sale.

Two-thirds of federal oil and gas is sold to marketers, pipelines, or refiners that are affiliated with the lessee and, hence, do not have competing interests. For those

BOX 2.
POSTED PRICES AND SPOT PRICES

Posted prices, which have been the basis for valuing most federal oil, are prices that the principal purchasers in individual oil fields advertise that they will pay for the product from that field (generally purchased at metering locations, at the wellhead, or at central accumulation points). They offer to pay that price for all of the product delivered in the ensuing period—until the posting changes—but neither party commits in advance to the transaction. Postings generally change every week or less often.

Spot prices, by contrast, reflect the prices that sellers and buyers negotiate for individual short-term contracts, generally committing themselves to produce or take delivery of a certain volume of the product at some time in the next one or two months at a certain location (generally a regional pipeline hub). Those contract prices can change daily or even hourly. Short-term contract prices are commonly indexed to posted prices, futures-market prices, or other reported spot prices. Conversely, purchasers have an eye on spot markets when setting their posted prices.

The spot prices that newspapers and other sources report are commonly \$2 to \$3 per barrel higher than the posted prices for oil of comparable quality. One reason is that producers in many parts of the country are able to sell for “premium plus,” offering their product under the terms of the posting but at a premium above the posted price. (Some economists believe that buyers pay a premium on top of their posted price rather than simply raise that price because states base production taxes on the posted price.) Only in California do competitive circumstances hold that premium down, so oil sells at the actual posted price.

Another reason for the difference between posted and spot prices derives from differences in the terms of posted and spot sales. Most important are transportation costs: spot sales often call for delivery at regional transportation hubs, whereas postings are for delivery back at the wellhead or a central accumulation point for the oil field. Also, spot sales entail additional marketing costs (such as search costs, legal fees, and financing costs) and reflect the price uncertainty that sellers in spot markets face. Between the signing of the contract and delivery, participants in spot markets must bear the risk of adverse price movements or incur the costs of hedging against such movements.

non-arms-length transactions, a new regulation published on March 15, 2000, requires that lessees impute a unit value at the lease site on the basis of prices published for regional spot markets, with discounts for differences in location and quality.⁷ The previous rule had usually required that lessees impute value using the actual price for a nearby arms-length sale or the posted price for the oil or gas field. MMS estimates that the new price rule for non-arms-length sales will increase royalty payments by \$67.3 million per year.

7. See Department of the Interior, Minerals Management Service, “30 CFR Part 206, Establishing Oil Value for Royalty Due on Federal Leases; Final Rule,” *Federal Register*, Part II (March 15, 2000).

TABLE 1. REVENUES FROM FEDERAL MINERAL LEASES AND THE SALES VALUE OF OIL AND GAS PRODUCED ON FEDERAL LANDS, 1998
(In millions of dollars)

	Offshore Leases	Onshore Leases	Total
Revenues			
Oil Royalties	908.5	132.2	1,040.7
Gas Royalties	<u>1,795.2</u>	<u>421.2</u>	<u>2,216.4</u>
Subtotal	2,703.7	553.4	3,257.1
Coal and Other Royalties	57.4	368.0	425.4
Bonuses ^a	1,320.3	134.2	1,454.5
Rents ^a	258.5	39.2	297.7
Other Revenues ^{a,b}	<u>-17.3</u>	<u>5.1</u>	<u>-12.2</u>
Total	4,322.6	1,099.9	5,422.5
Sales Value			
Oil	6,241.2	1,358.1	7,599.3
Gas	<u>11,374.5</u>	<u>3,669.4</u>	<u>15,043.9</u>
Total	17,615.7	5,027.5	22,643.2

SOURCE: Congressional Budget Office based on preliminary information from Department of the Interior, Minerals Management Service, *Mineral Revenues 1998*, Tables 3 and 7.

NOTE: These numbers exclude revenues and sales values for production from Indian lands.

e. Reflects the value of all minerals recoverable from federal leases.

b. Includes minimum royalty payments (an annual per-acre fee assessed in place of percentage royalties if production is below a specified minimum level), payments from legal settlements, and other fees and recoupments.

How Much Money the Royalty Program Collects

In 1998, the Minerals Management Service collected nearly \$3.3 billion in oil and gas royalties from federal lands and nearly \$1.8 billion in bonuses and rents (see Table 1). Only about \$1.0 billion of the collections that year—a period of depressed oil prices—were from oil royalties, including about \$0.2 billion in sales of royalty oil to eligible small refiners. Federal oil and gas account for 26 percent and 34 percent of national oil and gas output, respectively (see Table 2). Federal onshore leases, which have generated much of the controversy that underlies calls for royalty reform, account for less than 5 percent of the nation's total oil output. In 1998, they yielded just \$132 million in oil royalties.

TABLE 2. COMPARISON OF FEDERAL AND TOTAL U.S. PRODUCTION OF OIL AND GAS, 1989-1998

	Crude Oil (Millions of barrels)			Natural Gas (Billions of cubic feet)		
	Federal Production	Total U.S. Production	Federal Production as a Share of Total (Percent)	Federal Production	Total U.S. Production	Federal Production as a Share of Total (Percent)
1989	438	2,779	15.8	5,097	18,095	28.2
1990	470	2,685	17.5	6,294	18,594	33.8
1991	449	2,707	16.6	5,730	18,532	30.9
1992	487	2,617	18.6	5,975	18,712	31.9
1993	490	2,499	19.6	6,242	18,982	32.9
1994	488	2,432	20.1	6,446	19,710	32.7
1995	531	2,394	22.2	6,430	19,506	33.0
1996	560	2,360	23.7	6,924	19,751	35.0
1997	596	2,355	25.3	7,018	19,866	35.3
1998	589	2,282	25.8	6,755	19,824	34.1

SOURCE: Congressional Budget Office based on information from Department of the Interior, Minerals Management Service, *Mineral Revenues* (various years).

NOTE: Excludes production from Indian lands. Crude oil includes lease condensate (a liquid that sometimes comes out of gas wells). Natural gas is marketed production, which excludes extraction loss.

A relatively small, but controversial, part of total royalty collections is the result of government audits. Programs to detect underpayment of royalties brought in \$137 million in 1998 from all leases (see Table 3). Federal detection programs include separate efforts to audit royalty collections (in cooperation with state governments and Indian tribes) and to investigate the sales volumes, claims for deduction of transportation and processing costs, and royalty rates that lessees report.

Where the Royalty Payments Go: Allocating Federal and State Shares

Federal revenues from oil and gas leases go into the government's Reclamation Fund and other budget accounts (where they are to be spent by the agencies that oversee federal lands, subject to appropriation) and into the general fund of the U.S. Treasury (where they can be spent on other programs, subject to appropriation). Part of those revenues are subsequently disbursed to the states in which federal oil and gas production takes place, with the precise distribution set by the Mineral Leasing Act or other laws that govern leasing. In addition, some royalty oil has been delivered to

TABLE 3. REVENUES FROM THE PRINCIPAL PROGRAMS TO DETECT UNDERPAYMENT OF FEDERAL ROYALTIES, 1989-1998

	Revenues (Millions of dollars)
<hr/>	
1989	137
1990	99
1991	129
1992	170
1993	190
1994	307
1995	256
1996	73
1997	77
1998	137

SOURCE: Congressional Budget Office based on information from Department of the Interior, Minerals Management Service, *Mineral Revenues 1998*, Table 7.

the Strategic Petroleum Reserve, in effect diverting federal receipts to accounts of the Department of Energy.

In 1998, states received \$324 million, or about 10 percent, of total federal royalties from oil and gas—with most of that going to the few states that have onshore federal leases. Two states, New Mexico and Wyoming, received nearly 75 percent of those disbursements (see Table 4). As a result, state governments have a major interest in the outcome of proposals for reforming federal royalties.

THE COSTS OF GETTING ROYALTY OIL AND GAS TO MARKET

Getting crude oil and natural gas from the production well to the first purchaser involves several steps. Basic supply activities include gathering, treating, transporting, processing, and marketing. Each of those activities adds value to the product and increases the price that purchasers will want to pay for it.

In the current debate over royalty reform, much of the disagreement between holders of federal leases and the government revolves around the government's position that lessees have a duty to market royalty product. Under current regulations, lessees are liable for the cost of gathering and treating the government's royalty share (that is, making sure it is a marketable product) and any costs of finding buyers

TABLE 4. DISBURSEMENTS TO STATES FROM FEDERAL OIL AND GAS ROYALTIES, 1998 (In millions of dollars)

State	Oil Royalties	Gas Royalties	Total
New Mexico	22.1	121.9	144.0
Wyoming	28.5	65.1	93.6
Colorado	6.1	8.9	15.0
Alabama	0.2	13.1	13.2
Utah	3.3	7.5	10.8
California	8.5	1.7	10.1
Louisiana	3.9	6.1	10.0
Montana	2.2	1.7	3.9
Alaska	0.5	1.9	2.4
Oklahoma	0.2	2.1	2.3
All Other States	<u>5.4</u>	<u>13.2</u>	<u>18.7</u>
Total	80.9	243.2	324.1

SOURCE: Congressional Budget Office based on information from Department of the Interior, Minerals Management Service, *Mineral Revenues 1998*.

and making sales (that is, marketing), but not for the costs of transporting and processing it.

Gathering and Treating to Provide a Marketable Product

“Gathering” is the movement of bulk oil or gas from the well to a central accumulation point where it is “treated” (to separate out water and to remove dangerous gases and other impurities) and metered for royalty purposes. Some initial separation—of natural gas from oil or of gas liquids from natural gas—may also occur at the well-head. Removing water reduces the cost of moving the oil and gas by lowering the total volume to be moved and taking out corrosive substances. Additional treatment further lowers the cost of storing and moving the product by reducing its volatility and eliminating poisonous substances. Under current regulations, lessees are responsible for the costs of gathering and treating even if the metering point and the treatment facilities are off the lease site.

The costs of gathering and treating the product are generally only a small fraction of total lifting costs (costs that cover all activities related to pumping oil and gas and servicing wells). Those lifting costs average about \$3.50 per barrel of oil (or its

TABLE 5. SALES VALUE AND COSTS TO LESSEES OF PRODUCING FEDERAL OIL AND GAS, 1998

Dollars per Barrel of Oil Equivalent	
Average Sales Value of Oil and Gas	12.50
Average Costs to Lessees	
Federal royalties	1.80
Local production taxes	0.70
Direct lifting costs ^a	3.50
Finding costs ^b	5.00

SOURCE: Congressional Budget Office based on information from Department of Energy, Energy Information Administration, *Performance Profiles of Major Energy Producers 1998*, DOE/EIA-0206(98) (January 2000), and *Oil and Gas Development in the United States in the Early 1990's: An Expanded Role for Independent Producers*, DOE/EIA-0600 (October 1995); and from Department of the Interior, Minerals Management Service, *Mineral Revenues 1998*.

NOTE: To calculate unit sales value and royalties, natural gas is converted to barrels of oil equivalent (that is, with an equivalent heat content) on the basis of 0.19 barrels of oil per 1,000 cubic feet of wet marketed gas.

- a. Defined by the Energy Information Administration as spending on well operations and maintenance, well workovers, operation of fluid injection and improved recovery programs, operation of gas processing plants, and overhead. Direct lifting costs include gathering and treating but exclude marketing activities.
- b. Spending on exploration and development divided by additions to reserves (other than net purchases of reserves).

equivalent, in the case of natural gas) (see Table 5). But few lease sites have the same requirements for gathering systems, and few product streams have the same requirements for treatment. Average gathering costs for federal leases range from 23 cents to 69 cents per barrel for crude oil and from one cent to 10 cents per thousand cubic feet for natural gas, according to the Minerals Management Service (see Table 6).

Those unit costs, however, can vary greatly with the size of the operation and the quality of the product. Because of the high fixed-cost component of pipeline, storage, and treatment activities, unit costs are lowest for the large offshore producers, which dominate federal lease production. Unit costs for small onshore leases—such as in the Powder River Basin of Wyoming—can be three times as high as the average gathering costs shown in Table 6. They are greater still if the oil is particularly heavy or contains large amounts of water.

TABLE 6. THE RANGE OF UNIT COSTS FOR GATHERING, TREATING, AND MARKETING FEDERAL OIL AND GAS

Type of Cost	Minerals Management Service's Estimate
Oil Production (Cents per barrel)	
Gathering	23 to 69
Treating	n.a.
Marketing	7 to 15
Gas Production (Cents per thousand cubic feet)	
Gathering	1 to 10
Treating	
Removal of hydrogen sulfides	18 to 38
Removal of carbon dioxide	8 to 14
Marketing	1 to 3

SOURCE: Congressional Budget Office based on information from Department of the Interior, Minerals Management Service, *Report of the Department of the Interior on H.R. 3334, the Royalty Enhancement Act of 1998* (April 30, 1998).

NOTE: n.a. = not available.

Transporting Oil and Gas Beyond the Lease Site to Enhance Its Value

“Transportation” is the movement of treated product beyond the royalty measurement point and off the lease site to the point of first sale (often at a regional pipeline hub or a refining center). Transportation only applies to separated product, not bulk product. If the delivery point is indeed off the lease site and beyond the measurement point, MMS allows the lessee to deduct the costs of such transportation from sales proceeds before calculating royalty payments. Allowable transportation costs may represent actual charges for transactions with unaffiliated transporters; otherwise, federal regulations describe how those allowances are to be determined.

The standard rules for allowable transportation costs are subject to several exceptions. One is for movement of bulk product in a pipeline from certain older offshore leases to treatment facilities onshore, for which MMS allows a full transportation deduction. (With most newer offshore leases, cost considerations favor siting treatment facilities on the offshore production platforms.) Another exception is for movement by pipeline of gas from certain fields that have high concentrations of carbon dioxide (CO₂), for which the government shares the costs of moving the gas to a CO₂ treatment plant.

Processing Natural Gas to Enhance Its Value

Producers may also enhance the value of their natural gas through what is commonly called “processing.” Unlike treatment, which removes impurities, processing extracts marketable substances. If a sale occurs after processing (regardless of whether it takes place on or off the lease site), MMS generally allows lessees to deduct any costs of processing from the sales price in determining royalty value at the lease site. In some cases, allowable processing charges represent actual charges for transactions with unaffiliated processors; in other cases, they are determined according to federal regulations. Allowances for processing may not exceed the value that such processing adds. In addition, MMS collects royalties on lessees’ sale of any coproducts that result from processing—with appropriate discounts for transportation costs.

In a very few cases, MMS also allows federal lessees to deduct their costs for certain “extraordinary treatment” activities, much like the costs of processing. Specific examples include treatment of natural gas deposits that have high concentrations of CO₂ or poisonous hydrogen sulfides. Production from those leases might not be profitable if producers had to pay the full costs of treatment to remove those substances.

Marketing as a Condition of Marketability

Another type of expense that lessees incur is for marketing. Current regulations do not define “marketing” explicitly. However, the regulations that guide the calculation of federal royalties do not allow lessees to deduct costs for any actions they may take (aside from extraordinary treatment or transportation) to make their product available and acceptable to buyers. Such actions include finding buyers (whether through brokerage firms or their own advertising), providing short-term financing, and paying for such ancillary services as product transfer (say, from truck to pipeline) and temporary storage.

A further service implicit in the terms of a sale relates to acceptance of the risk of adverse price movements. The terms may reflect the firm price and prompt delivery implicit in selling at local posted prices, in which case the buyer accepts that risk. Or they may reflect the variable price (generally indexed to price movements in other markets) and deferred delivery that spot contracts call for, in which case the seller accepts the risk (see Box 2 on page 7). Any price risk associated with a spot sale—or with efforts to hedge such risk with futures contracts—would represent an additional cost to the seller. Generally, if the seller accepts the risks, buyers place a greater value on a product than they would otherwise.

MMS estimates that marketing activities cost buyers between about 7 cents and 15 cents per barrel, although that figure generally represents only brokerage fees (see Table 6 on page 13). The costs of all marketing-related activities will show up in the price of the product and, hence, will affect the royalty payment. Having more services included as part of the basic sale generally means a greater value to buyers, a higher price, and a bigger royalty payment.

BASIC PROPOSALS FOR REFORM AND THE ARGUMENTS FOR AND AGAINST CHANGE

The legislative proposals for royalty reform that the petroleum industry is supporting envision three types of change:

- o *Collecting Royalties in Kind.* This proposal would require that the government collect most of its royalties in kind, as a percentage of the physical volume of oil and gas extracted at the lease site. The government would then sell that royalty product on its own.⁸ The goal of this proposal is to simplify royalty calculations.
- o *Shifting Certain Costs of Supplying Royalty Oil and Gas.* This change would limit lessees' liability for some of the costs that they now pay for treating, moving, and marketing royalty product—and thus effectively lower the unit value of oil and gas on which royalties are based. This proposal would also increase the allowable deductions for transportation and processing costs.
- o *Restricting MMS Audits.* This proposal would restrict the government's audits of royalty collections (for example, by limiting the time that MMS had to conduct audits) to reduce lessees' uncertainty about their payments.

Those proposals are generally not presented as alternatives but rather as different parts of a broad industry plan for reform.

The Administration has supported a different change, in which MMS alters the basis for valuing oil sold in non-arms-length transactions. MMS published a final rule implementing that change on March 15, 2000. The rule was to take effect on June 1 but included a three-month, interest-free grace period, through September 1.

8. Discussions of current royalty-in-kind sales appear in Department of the Interior, *1997 Royalty in Kind Feasibility Study*; and General Accounting Office, *Federal Oil Valuation: Efforts to Revise Regulations and an Analysis of Royalties in Kind*, GAO/RCED-98-242 (August 1998).

The ultimate status of that rule is not clear, however. The industry has initiated a legal challenge to it, arguing in part that lessees should be allowed to deduct the costs of marketing crude oil, especially if MMS is going to index royalty values to spot prices in downstream markets.⁹ Support for the industry's position may come from a recent federal court decision involving royalty payments on natural gas from federal leases.¹⁰ The court rejected a transportation allowance rule that had allowed MMS to collect royalties on the marketing costs (or, equivalently, on the value added by marketing) that federal lessees paid in the course of selling their gas downstream from the lease site.

Several concerns have prompted the industry's push for royalty reform. The industry believes that the current system (even without the new valuation rule) sets too high a value for federal oil and gas and thus requires too high a royalty payment. In addition, lessees complain that they are subject to an expensive, time-consuming, and uncertain process of audits and revaluations. Moreover, lessees contend that the government should let them deduct the costs of moving, treating, and marketing oil and gas beyond the lease site, costs that boost the selling price used to calculate royalties. They argue that one way the government could pay those costs and simplify the calculation of royalty payments would be to collect royalties in kind (RIK).

MMS agrees with the industry that the process of collecting royalties could be made more certain. It is pursuing procedural changes that it believes will reduce the industry's administrative burden. It is also studying the feasibility of taking royalties in kind in more situations (see Box 1 on page 4). But the agency disputes the claim that RIK would resolve all problems with the current system fairly and expeditiously. It makes at least three arguments against a broad requirement that it collect royalties in kind and against other industry-supported reforms.

First, MMS believes that RIK might not be cost-effective at many remote, low-volume lease sites (where the costs of putting together a marketable amount of product are high) and those in uncompetitive circumstances (such as where pipeline owners set very high charges for transportation). Second, the agency disputes industry concerns that royalty payments are too high. Indeed, it argues that in some uncompetitive markets, the current system recovers too few royalties. Third, MMS believes that lessees should continue to be liable for the costs of placing royalty product in a marketable condition and selling it.

9. For a discussion, see Independent Petroleum Association of America, "IPAA Sues to Prevent Interior Department from Assessing More Unlawful Royalties" (press release, Washington, D.C., April 11, 2000), available at www.ipaa.org/departments/communications/PR2000/pr041100.htm.

10. *Independent Petroleum Association of America v. Armstrong*, 91 F.Supp. 2nd 117 (D.D.C., March 28, 2000).

The legislative proposals for reform and the government's rule on oil valuation are closely related. The government's actions to revise its rule gave impetus to the industry's desire to change the royalty program. And from a budgetary perspective, the status of the valuation rule has complicated efforts to estimate the federal cost of reform legislation. Although the Congressional Budget Office (CBO) would not be required to estimate the cost of a regulatory change, current regulations form the baseline against which CBO would estimate the cost of legislative changes.

CHAPTER II

ECONOMIC AND BUDGETARY IMPACTS

OF ROYALTY REFORM

Calls to reform the federal royalty program spring from the competing pecuniary interests of the government and leaseholders as well as from their common desire to simplify a complex system. Legislative reforms that redefined the value of royalty oil and gas to exclude some treatment or gathering costs or that boosted allowable deductions for transportation or processing would increase the income of lessees at the expense of lower payments to the government. Conversely, new regulations that raised valuations for royalty oil would increase lessees' payments to the government. Those trade-offs would be dollar for dollar—unless the reforms also affected incentives to produce oil and gas, actual sales prices, or the costs of managing royalty payments.

The three industry proposals described in the previous chapter (collecting royalties in kind, shifting the liability for certain costs, and restricting government audits) and the government's new oil valuation rule all have the potential to affect the costs of the royalty program to the federal government. They could also affect the level of royalty payments, both directly and indirectly (through production incentives or price uplift). In theory, such changes could also have an impact on production and prices of federal gas and oil. But those secondary economic effects are likely to be negligible, for two reasons. First, U.S. production of oil and (to a lesser extent) natural gas is largely insensitive to small changes in expected returns, and the changes in royalty costs and in uncertainty that the reforms would produce are fairly limited. Second, the government's opportunities to realize price uplift from selling royalty product itself and to market that product at a lower cost are also limited.

Specifically, the conclusion that the royalty reforms would have a negligible effect on production of oil and gas from federal lands—and thus that the trade-off between lessees' incomes and net budgetary receipts would probably remain dollar for dollar—rests on three factors. First, federal lessees pay, on average, only 10 percent to 15 percent of the market value of their product to the government, and their potential cost savings from those reforms would be a small portion of that figure. Second, for new leases, lessees will tend to adjust their bonus bid in response to changes in royalty costs, leaving plans for overall development unaffected. And third, domestic oil and gas production is what economists describe as highly inelastic. In other words, producers are limited in their ability to respond to price increases or cost reductions of any size.

BOX 3.
FEDERAL ROYALTIES AND ECONOMIC EFFICIENCY

The Minerals Management Service describes its mission, in part, as promoting the development of resources in a way that ensures that the public receives fair market value for its oil and gas. In addition, it aims to collect royalties in a timely, accurate, and cost-effective manner.¹ The debate about royalty reform has focused on those issues of “fair market value” and “cost-effective” collections. But there are also significant concerns about how well the royalty program works to promote cost-effective development of federal oil and gas resources. Is the program economically efficient? And will the reforms under consideration increase that efficiency?

The answers to those questions hinge on assessing the social costs of developing public lands and the efficiency of the basic policy of making federal lands available through public auctions. At the most general level, the nation is economically efficient if it produces the goods that people most desire at the lowest cost—a situation that economists characterize as one in which no one can be made better off without making someone else worse off. Market economies tend to approach that outcome if, among other things, the private costs of producing a good reflect the costs to society of that good.

In the case at hand, economic efficiency means that the prices that developers pay to exploit public resources should fully reflect the social costs of that activity. Federal lessees may be paying too little (and thus producing too much) under several circumstances. First, if their activities cause environmental damage or prevent other, more highly valued uses of public lands, those lands will not be put to their best use. Second, if lessees find federal production more profitable than development on otherwise comparable private lands, the nation will expend more resources than necessary to produce oil and gas. One way that

1. Department of Interior, Minerals Management Service, *Strategic Plan, Fiscal Years 2000-2005* (March 2000), Table 1.

In the short run, their production response is restricted by the amount of lifting capacity for oil and gas wells. Adding new capacity is both expensive and time-consuming. In the long run, the high cost of finding and developing new resources limits supply. The history of oil markets over the past three decades—with several major swings in world oil prices but little accompanying change in domestic production—supports the view of insensitive U.S. supply. Forecasts by the Energy Information Administration indicate that even a 25 percent increase in crude oil prices would stimulate little more than a 5 percent increase in oil output after 10 years.¹ The production response after only one year is estimated to be close to zero. Nevertheless, the changes in production incentives and production responses caused by royalty reform could appear significant to the businesses that experienced them.

1. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (December 1999).

BOX 3.
CONTINUED

situation could occur is if the federal royalty program offered land on more favorable terms than were available for private lands.

In other circumstances, federal production may be too low. For example, if some lessees have a strong market position in relation to certain buyers, they may be withholding production to get a better price. Or if lessees in some regional markets have a particularly weak market position in relation to buyers, they may not be receiving a competitive price for their product.

Whether for existing leases or new leases, royalties are generally not an effective tool for making the market pay the full social costs of development. On existing leases, for which changes in royalty costs could have the biggest impact on production incentives (since oil and, to a lesser extent, gas producers are generally unable to pass changes in costs on to buyers), there is little agreement about the value of the environment and competing uses of federal lands or about the costs of market impediments. Considering environmental effects alone, the full costs of production at different sites are too diverse to be captured by a single royalty rate. A given change in royalty costs could enhance efficiency for some leases and diminish it for others.

For new leases, the basic design of the minerals auction—which identifies both the lands to be developed and the businesses to do the job—further blunts the effect of royalty reforms on production incentives and economic efficiency. The two-tier system of bonuses and royalties generally ensures that changes in bonus payments will offset any changes in expected royalty payments, with little impact on overall profitability or the scale of future development. That is true whether reforms would change the rules for establishing the basis for royalty value (such as by collecting royalties in kind, shifting costs to the government, and indexing values to spot-market prices) or change the process of enforcing royalty collections. If lessees expect to pay more to produce oil and gas, they will bid less initially, and vice versa.

Much of the debate over royalty reform has focused narrowly on lessees' incomes and the government's royalty receipts, but the effects of reform on economic efficiency in a wider sense (including costs other than those faced by lessees and the federal government) are also of concern. In principle, all leaseholders and the government could see immediate benefits from a proposed reform, but overall efficiency would still suffer if, for example, the environment or other sectors of the economy were harmed as a result. Groups or businesses with a vested interest in those other costs (such as people who would use public lands for other purposes) may thus have a stake in the royalty rules. Determining how particular types of reform would affect economic efficiency is beyond the scope of this analysis, but those effects would probably be small (see Box 3).

COLLECTING FEDERAL ROYALTIES IN KIND

In theory, if the government sold royalty product on its own rather than relying on lessees to market it, royalty payments and program costs could be affected in several ways. Paying royalties in kind could diminish lessees' uncertainty about royalty costs and cause them to boost production, making additional oil and gas available to the government to sell. In addition, the government could realize economies of scale in marketing and counter the market power of local purchasers, which could boost the price of the royalty product that it sells. The government could also spend less on managing disputes about royalty value. In practice, however, the opportunities for gains in each of those areas are probably very limited.

The assessment that follows considers the effects only of legislation that would require the government to take all of its royalties in kind. The budgetary consequences of a more limited proposal—in which the Minerals Management Service sold royalty product only where it was likely to get a higher price than lessees—could be more favorable.

Uncertainty About Royalty Payments

Proponents of RIK claim that it would be easier for producers to turn over a portion of their product to the government than to calculate royalty payments. In principle, more certainty about their royalties should raise lessees' expected profitability and, as a result, create an incentive for them to boost production from federal leases. But in reality, lessees' profit expectations would change very little. For bidders on new leases, any gains in expected future income would result in higher bonus bids, so overall profitability would remain the same. For holders of current leases, any reduction in uncertainty about the unit value of their product would not resolve all uncertainty about royalty payments. RIK reform only addresses lessees' concern about the application of the government's valuation rules and the outcome of subsequent audits of unit value. Government audits of reported production volumes and allowable cost deductions would remain and might even become more critical than before.

Moreover, uncertainty about royalty payments is only a small part of the overall risk of producing oil and gas, trailing far behind concerns about the amount of resources in place and sales prices for the product. Thus, it is likely that lessees' overall uncertainty about revenues and costs—and, hence, about expected profits and production—would change very little. That would be the case for all leases, whether existing or new, onshore or offshore, oil or gas.

Economies of Scale in Marketing and Market Power

The government would gain from RIK reform if it could sell oil and gas for a higher price than current lessees can. Opportunities for such price uplift would exist if it could exploit economies of scale to offer buyers a more attractive package of services or if the government could exert additional market power against purchasers. Only for small and remote leases, operated by small producers, would the circumstances that favor price uplift be present. Even if those circumstances existed, however, it would still be more economical to market all federal oil and gas (royalty plus nonroyalty shares) together than to market it separately. Moreover, the government's ability to realize higher prices will always be limited by its lack of a profit motive.

In principle, by drawing royalty product from a number of small leases, the government could assemble a bigger sales volume than individual lessees now can. Buyers could save money because of the shortened time that federal oil and gas would stay in interim storage facilities awaiting transport and because of the increased batch size that would enter pipelines. The prospects for such marketing gains would be stronger if the government could bring the product to central hubs and periodically auction off large batches (whether as a specific volume or, more likely, as a guaranteed daily supply over some period) than if it tried to continuously sell the output of individual leases. In general, such opportunities for aggregation are best for offshore oil and gas. Onshore, where many federal leases produce small volumes and are not integrated with pipeline networks, the costs of marketing royalty and nonroyalty product together, as lessees now do, would probably be lower than the total costs of marketing them separately.

The ability to achieve economies in marketing may be closely related to the government's ability to overcome market barriers that small regional producers now face in dealing with large regional purchasers and pipelines. Having more to sell can increase the market power of the seller in relation to the buyer. But the ability to aggregate that greater volume may depend on the seller's access to pipelines, storage, or processing facilities at competitive rates. The government may not be able to improve on below-market prices simply by taking royalty product in kind if the market forces that are holding down prices do not change. Also, capitalizing on any marketing advantage it might have would be a difficult prospect given the government's lack of pecuniary incentives, its relative inexperience in selling oil and gas, and a political environment that would most likely constrain its marketing decisions.

Program Management Costs

Taking royalties in kind could affect the government's costs of managing royalty collections in two ways, one related to potential savings on dispute management and the other to new expenses for marketing. Federal lessees could also save on costs

related to disputes as well as save the expenses of marketing royalty oil and gas, which could make production more profitable than before. However, on net, higher program costs for the government are almost a certainty, and lessees would be unlikely to see significant savings or increased profitability.

The costs of managing disputes could drop for both lessees and the government alike if they engaged in fewer disputes over royalty value than they do now. Such a drop could boost net government receipts both directly (by lowering government spending) and indirectly (by boosting lessees' profitability and thus their production from federal lands and royalty payments). However, any reduction in management costs would require that new disputes over royalty volumes and allowable costs did not displace old disputes over value. As previously discussed, unit value is only one source of uncertainty for lessees. Disputes will arise whenever the potential gain from pursuing a complaint exceeds the cost of bringing it.

In terms of market expenses, the government would incur new costs related to efforts to sell royalty product, such as costs to find buyers, write and enforce sales contracts, and meet any special terms of delivery (related to location or processing). Lessees, by contrast, could realize some savings by not selling the oil and gas that they paid to the government in kind, but it is not clear how much they would save. To the extent that marketing costs such as brokerage and contracting fees were fixed (independent of the volume of sales), lessees would not save anything. However, some marketing costs related to storage and movement vary according to volume. Any savings that lessees achieved by avoiding the cost of marketing royalty product would make current operations more profitable. For existing leases, that profitability could encourage additional production; for new leases, it would be offset by increased bonus payments, with no effect of the scale of development.

The question of who should pay to market royalty product, which is at the center of the debate over RIK proposals, also arises in the discussion of proposals that would shift cost liabilities to the government.

SHIFTING THE LIABILITY FOR CERTAIN COSTS FROM LESSEES TO THE GOVERNMENT

Recent proposals for reform would shift to the government some costs that lessees now pay for gathering, treating, and marketing federal oil and gas. Reforms might also expand the deductions from sales proceeds that lessees are allowed to make for transporting and processing their product. Those changes could affect production costs and incentives and prompt a rise in lease production and royalty payments. However, the general insensitivity of oil and gas production to changes in price suggests that any boost in royalty payments because of increased production would

only slightly offset the costs shifted to the government: on net, government revenues would fall rather than rise as a result of such shifts.

Costs of Gathering and Treating Royalty Product

The issue of who pays gathering costs for royalty product arises with changes in liability for the costs of moving that product to central accumulation points off the lease site before sale. Some lessees propose that the government bear such costs by, in effect, redefining that gathering activity as transportation and allowing its cost to be deducted from sales proceeds when calculating royalty payments. In principle, shifting gathering costs to the government could encourage an increase in production, but that increase is likely to be small.

For existing leases, the impact of lower costs would be most likely to affect total federal production by encouraging lessees to postpone abandoning marginal wells. However, even that effect would be minimal because the government already has programs in place to reduce the royalty rates for properties reaching the end of their productive life.

For new leases, even if lower gathering costs did not stimulate increased production, they could encourage producers to situate central accumulation facilities in otherwise uneconomical locations. (On existing leases, the gains at stake would not be sufficient to make lessees move those expensive facilities.) The siting of central accumulation facilities is based on economic decisions that take into account the physical distribution of wells and local topography, the proximity of a field to existing pipelines, and the costs of constructing and operating gathering lines, treatment plants, and storage tanks. Shifting the costs of gathering to the government might cause lessees to locate central accumulation points farther away from the lease site than they would otherwise find cost-effective. Or it might prompt them to produce more oil and gas that requires movement off the lease site. Either way, total production would be unlikely to change, and the federal government would be unlikely to see increased royalty payments that would compensate it for accepting the costs of gathering.

The same situation applies to the siting of new oil-treatment facilities: producers would want to situate those facilities farther from production sites than they could afford to otherwise. The total costs of supplying oil and gas would increase because more of the product moved would be unseparated, bulk product than before. (Virtually all oil and gas production requires some separation and treatment.) Currently, when an allowance for transportation costs is granted, it generally excludes any costs for moving water or other contaminants in the bulk product to the treatment point.

A related element of reform addresses the eligibility of gas producers to take cost allowances for treating natural gas deposits with high concentrations of carbon dioxide or hydrogen sulfides. Expanding those treatment allowances would encourage increased development of those types of otherwise unprofitable gas resources from both existing leases and new leases.

Allowances for Transportation and Processing Costs

Proposed changes in the formula for calculating transportation and processing allowances (separate from reforms that would alter what counts as transportation or who is eligible for such allowances) would most likely boost allowable deductions. Such changes would favor lessees who engaged with affiliated businesses for those services and would enhance the profitability of using affiliated pipelines and processing plants.

If the new calculations brought the allowable rates more in line with lessees' actual costs of supplying those services, the result would be improved utilization of transportation and processing facilities. That would reduce the cost of supplying federal oil and gas. If the calculations reduced the deduction below actual costs, however, the government could end up paying for the diversion of oil and gas from what might otherwise be lowest-cost transportation routes or for excessive extraction of coproducts.

Costs of Marketing Royalty Oil and Gas

The issue of who should bear the costs of marketing the government's royalty share arises in proposals that such costs be deductible from royalty payments or that the government take its royalties in kind. Federal lessees currently absorb those marketing costs. Shifting the costs to the government under either type of reform would lower the effective royalty rate that lessees paid and could encourage them to increase production. However, the total costs (to lessees and the government together) of marketing federal oil and gas might rise.

With reforms to collect royalties in kind, marketing costs could shift to the government in either of two ways. MMS could collect the federal royalty share and do its own marketing. Or the government could contract with private marketers to collect and sell that product, as proposed in industry-supported reform legislation. Under that legislation, the government would pay the private marketers out of the proceeds from their sale of royalty product. With that approach, however, the savings to lessees could be less than the additional costs to the government—in other words, the total costs of marketing could increase—for at least two reasons.

First, specifying the appropriate incentives for private marketers of royalty product to operate efficiently could be difficult. It is not clear what additional service a marketer could provide to increase the value of the royalty product (beyond what lessees can now obtain) and what incentives that marketer would have to pass any savings that it did achieve on to the government. Those concerns are especially acute with RIK proposals that would have the government compensate the marketers for their full costs.

Second, government marketing of the royalty share could result in a duplication of marketing effort. That would be the case if lessees' efforts to sell product included significant fixed costs, which would not change if they no longer had to market the federal share of their output. Such costs could include the effort of finding customers, fees for contracting and insurance, and the need to transport product in set batch sizes.

RESTRICTING MMS AUDITS OF ROYALTY PAYMENTS

Reform proposals have included requirements that the Minerals Management Service limit various facets of its audits of royalty payments—particularly the documentation of royalty values that the agency requires and the time that MMS has to complete audits. Proponents of those changes aim to reduce lessees' uncertainty about the ultimate amount of their payments and to lower their costs of accounting for royalty values and volumes.

In principle, any reductions in lessees' uncertainty or costs would spur more oil and gas production. Restrictions on audits might also end up lowering royalty payments, which could further boost production. Historically, the payment mistakes that MMS audits correct have been underpayments, on net, since those audits generate revenues for the government (see Table 3 on page 10). Shortening the audit period would mean that the government would need additional resources to complete its audits on time. Otherwise, some mistakes in payment might pass through the system uncorrected.

The prospect of additional production is most relevant for existing leases, since any gains in the expected returns from new leases should show up in the bonus bids. However, even with changes to audits, existing lessees would still face significant production and price uncertainty and thus be unlikely to boost production levels simply in response to audit reforms. In addition, royalty payments would most likely be lower. As a result, the only savings to the government from this type of reform would come from reduced spending on audits.

INDEXING OIL VALUATIONS TO SPOT PRICES

MMS's recent change to its valuation rule for federal oil—to use spot-market prices rather than posted prices, with adjustments for differences in location and quality—could boost royalty collections. Non-arms-length transactions, to which the new rule applies, account for as much as two-thirds of federal oil production. And as Box 2 on page 7 explained, spot prices are commonly higher than posted prices. The actual amount of the royalty increase will depend on the location and quality adjustments that are part of the new rule. If those adjustments to spot prices are smaller than the price differences that lessees actually face—as complaints from the industry indicate—the new rule will raise royalty payments.

Increased payments could, in turn, result in lower production of oil (and of the gas that is associated with that oil). But the size of the additional payments would be small—\$67.3 million per year, according to MMS—compared with total payments of oil royalties (about \$1 billion in 1998). And, as noted earlier, U.S. oil production is not very responsive to price changes. However, the impact on lessees' profits and production would be more significant if a large share of the additional payments came from onshore producers (who paid oil royalties of \$132 million in 1998). As with other reforms, the effects of the rule change are most relevant to existing leases; changes in royalty payments would have little effect on the scale of development for new leases.

CHAPTER III

ISSUES IN ESTIMATING

THE FEDERAL COST OF ROYALTY REFORM

The Minerals Management Service predicts that the industry's proposed changes to require in-kind royalties and shift certain expenses would cost the federal government money, on net. The petroleum industry, by contrast, has predicted a gain to the federal budget from the combination of those two changes.¹ Those estimates differ about whether the government would realize an increase (or uplift) in price and thus in gross proceeds if it sold royalty product on its own and about what additional costs the royalty program would face. MMS also predicts a budgetary gain from its new rule to alter the way in which federal oil is valued, but the petroleum industry disputes that prediction.²

By and large, the Congressional Budget Office concludes that budgetary gains from increased production, price uplift, and program savings would not be sufficient to offset the costs that the reforms would shift to the federal government. However, making an independent assessment of the budgetary costs of reform is difficult because the language of specific proposals has been open to multiple interpretations and continues to evolve. Indeed, significant disagreement exists about what some of the activities named in legislation actually entail. Despite those difficulties, CBO would be required to estimate the federal cost of any legislation that changed the royalty program for oil and gas.

Legislative cost estimates, which CBO prepares for purposes of budgetary enforcement, may differ from the figures that industry groups or the Administration present to show the budgetary effects of reform. In general, the price tag that CBO would attach to reform legislation would be the net result of changes in government revenues and spending relative to amounts that are currently projected to occur under existing law—that is, in the absence of the proposed legislation. Three considerations

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1. For the government's perspective, see Department of the Interior, Minerals Management Service, *Report of the Department of the Interior on H.R. 3334, the Royalty Enhancement Act of 1998* (April 30, 1998), *Effect of Amended Language on H.R. 3334, Royalty Enhancement Act of 1998* (July 30, 1998), and *Estimates of Additional Costs Resulting from H.R. 3334, Royalty Enhancement Act of 1998, as Amended* (July 30, 1998). Also see testimony by Thomas R. Kitsos, Deputy Director, Minerals Management Service, before the Subcommittee on Energy Research, Development, Production and Regulation of the Senate Committee on Energy and Natural Resources, May 18, 1999. For an industry perspective, see Linden C. Smith, *Revenue Effects of H.R. 3334, the Royalty Enhancement Act of 1998*, testimony before the Subcommittee on Energy and Mineral Resources of the House Committee on Resources, May 21, 1998.
 2. For example, see testimony by Sylvia Baca, Acting Assistant Secretary for Land and Minerals, Department of the Interior, before the Subcommittee on Government Management, Information and Technology of the House Committee on Government Reform, May 19, 1999.

(besides CBO's assessment of how the legislation would alter production activities, prices, and program costs) could affect such a cost estimate.

The first is the baseline that CBO uses to project the net receipts from oil and gas royalties under current law. That baseline projection determines what the legislative changes are measured against. CBO will need to consider the status of the new oil valuation rule in developing its baseline for royalty receipts.

The second consideration is how MMS's costs and receipts (or changes in them caused by legislation) are divided between the mandatory and discretionary categories of the budget. Particular cash flows that could receive different budgetary treatment depending on legislative language include supply costs that shifted to the government, administrative costs, and payments to states. How a bill was written—and whether particular costs came out of mandatory or discretionary accounts—would determine the cost of the legislation.

The third consideration relates to identifying changes that would occur within a finite estimating period, known as the budget window. For example, reforms that lowered royalty payments in the long run (outside the budget window) could boost bonus payments in the short run.

THE BUDGET BASELINE AND THE OIL VALUATION RULE

MMS has substantial discretion under existing law in determining how it values federal oil and gas and how it collects royalty receipts. In theory, CBO's baseline projection of royalty receipts accounts for that discretion. An estimate of the federal cost of reform legislation would report changes in receipts or spending from the levels reflected in the baseline. Such changes would be the unique consequence of the legislation. In contrast, legislation that merely ratified program changes that MMS can make administratively would not alter federal costs from what they would have been without the legislation (in other words, the cost of implementing the legislation would be zero).

Legislation that mandates the collection of royalties in kind presents a case in point. Some proponents of reform believe that such a change would boost the market value of federal oil and gas and, hence, federal receipts. However, it is not always clear how much of that price uplift would be attributable to the reform legislation, since the government already has the authority to collect royalties in kind. (In fact, MMS is investigating the advantages of that approach in several tests.) Moreover, requiring that MMS take royalties in kind would not in itself alter the terms of sale or royalty proceeds: the government could end up selling at the same posted prices as lessees do now. And if the lack of competition in regional markets is holding

down prices, the government already has authority to seek a fair market value—through its valuation rules and the courts.

Other legislation that, for example, would restrict MMS's ability to implement rule changes could affect the federal cost of royalty-in-kind and other reform legislation by causing CBO to revise its assumptions about baseline royalty receipts. With its new rule for valuing federal oil that sells in non-arms-length transactions, MMS did not require legislation to implement the change.³ But CBO had an opportunity to estimate the budgetary impact of the change, while it was still in the proposal stage, through scheduled updates to its baseline. Those updates, in turn, can affect the budgetary impact that CBO estimates for subsequent legislation. For example, if it had been clear that MMS was indeed proceeding to implement such a rule, any price uplift that resulted from the change could have diminished the uplift that might otherwise have resulted from royalty reform legislation.

MANDATORY AND DISCRETIONARY ACCOUNTS

Under current law, CBO must account separately for changes in mandatory and discretionary spending when it prepares a cost estimate of a bill. Mandatory spending is authorized by permanent legislation and is subject to pay-as-you-go limits.⁴ Royalty receipts and bonuses are considered mandatory offsetting receipts, and disbursements of those offsetting receipts to the states are considered mandatory spending. Discretionary spending, which is controlled through the annual appropriation process, includes spending by MMS to administer the royalty program. Questions about budgetary treatment arise for three types of spending changes that can result from royalty reform: supply costs that shift to the federal government, administrative costs, and payments to states.

Supply Costs Shifted to the Government

Any new costs of supplying royalty product that lessees may deduct from their royalty payments could be mandatory or discretionary, depending on how the reform legislation was written. For example, direct deductions from lessees' payments—for treating, moving, or marketing—would count as increased mandatory spending. In other words, the collections required by law would decrease, and the estimated cost

3. The new oil valuation rule officially took effect on June 1, 2000 (pending a legal challenge). But before that date, the Congress had included moratoria on the implementation of the rule in appropriation legislation for MMS.

4. For a discussion of the different spending categories, see Congressional Budget Office, *Budget Options* (March 2000), Chapter 1.

of the legislation would reflect that drop in receipts. By contrast, an indirect deduction that was handled as a cash reimbursement subject to appropriations would count as discretionary spending and would not show up in the mandatory cost of the reform legislation.

Administrative Costs

Spending on program administration is generally subject to appropriations. As such, changes in most administrative costs—whether savings or increases—would not be reflected in the mandatory cost of the legislation authorizing the reform. However, as with supply costs that shift to the government, legislation can be written so that some new program costs show up as discretionary or mandatory spending. For example, if the government was required to market royalty product on its own, those new marketing expenses could be part of the general administrative costs that are subject to appropriations. Or the reform legislation could be written to give MMS authority to spend program receipts on marketing as necessary, without further appropriations. In that case, the additional administrative burden of marketing could contribute to an increase in mandatory spending.

Payments to the States

MMS disburses a share of net federal receipts from royalties, bonuses, and rents to the states where the production occurs. In general, states receive half of the receipts minus one-quarter of the federal government's cost of administering the royalty program (see Box 4). Those payments to states are considered mandatory spending, but the program costs on which the payments are partly based count as discretionary spending.

Estimates of the federal cost of proposals to alter the royalty program would account for changes in state payments in several ways. The boost to federal receipts from an increase in royalty values would be offset in part by a rise in state payments. Similarly, the loss of receipts from an increase in allowable deductions from lessees' royalty payments would be offset in part by a drop in state payments. And an increase in agency appropriations (discretionary spending) for managing the royalty program could diminish the state payments (mandatory spending). Whether some new cost to the federal government came out of royalty payments (as a reduction in offsetting receipts) or agency appropriations would affect the estimate of the cost of the legislation.

Two examples for onshore production from public-domain lands in the lower 48 states demonstrate that point (ignoring changes in royalty value and total administrative costs). If offsetting receipts dropped by \$1 because lessees were

BOX 4.
CALCULATING DISBURSEMENTS TO STATES

The precise formula for determining state payments varies according to the area in which the oil or gas is produced. For production in federal waters—that is, more than three miles from shore—the government retains almost all revenues. (One exception is proceeds from the so-called 8(g) zone of the Gulf of Mexico—resource deposits that straddle the three-mile line—which the federal government shares with coastal states.)¹ For the onshore, public-domain lands of the lower 48 states, the federal government shares half the royalties and other leasing revenues with the states where the oil and gas is produced, minus about 25 percent of the Congressional appropriations to three agencies (the Bureau of Land Management, the Forest Service, and the Minerals Management Service) for administering the mineral leasing laws in their respective regions.² For federal production in Alaska, the state receives 90 percent, net of a share of agency costs, of the proceeds from the North Slope. For the small amount of royalties that comes from acquired federal lands, other distribution formulas apply.

3. For a discussion, see General Accounting Office, *Minerals Management: Costs for Onshore Minerals Leasing Programs in Three States*, GAO/RCED-97-31 (February 1997); and Lawrence Kumins, *Outer Continental Shelf: Oil and Gas Leasing and Revenue*, CRS Issue Brief IB-10005 (Congressional Research Service, October 15, 1999). Legislation considered in the 106th Congress (S. 25 and H.R. 701) would require the sharing of all offshore revenues with coastal states.
4. Sharing of net receipts cost the states \$20.2 million in 1998. A detailed description of the receipts-sharing process for different regions of the country appears in Department of the Interior, Minerals Management Service, *Mineral Revenues 1998* (preliminary), Table 30. Also see General Accounting Office, *Minerals Management*.

allowed some new deduction (for treating, moving, or marketing), that loss would be partially offset by a 50 cent reduction in mandatory state payments. The federal cost of that legislation would reflect a net 50 cent *increase* in mandatory spending. (A change in discretionary spending—which, in any case, would depend on appropriation legislation—would not be required.) If the law instead required an appropriation of \$1 (an increase in discretionary spending) to pay for those costs to lessees, the increased spending for program management would result in a 25 cent reduction in mandatory state payments. In that case, the federal cost of the legislation would reflect only a 25 cent *decrease* in mandatory spending. (The increased discretionary spending would show up in future appropriation bills.)

THE BUDGET WINDOW

CBO's cost estimates reflect changes in receipts and spending for a budget window that includes the current year and the succeeding 10 years. For the purposes of

enforcing pay-as-you-go requirements, however, the relevant budget window is only five years—the current year and the following four years.⁵ A CBO cost estimate for royalty reform legislation could pick up changes in the timing of budgetary flows if the reform would pull receipts forward into the budget window or push them outside it. One example relates to changes in the timing of when the Minerals Management Service recovers disputed payments through audits (or reimburses disputed costs).

Another example relates to the trade-off between royalty and bonus payments, both of which count as offsetting receipts. For existing leases, the impact of legislation that reduced (or increased) royalty payments would be an immediate reduction (or increase) in royalty receipts. For new leases, that change in royalty receipts would be delayed until production began—up to one year for onshore properties and five or more years for offshore properties. But because the legislation would alter future profitability, it would also have an immediate impact on bonus bids—with lower royalties leading to higher bonuses, and vice versa. Overall, in present-value terms, royalty reform might have little effect on long-term mandatory spending. But up-front bonuses would generally show up within the budget window (for pay-as-you-go scoring), whereas most of the associated royalty changes (especially for offshore leases, which are the source of most bonus payments) would not.

LEGISLATIVE COSTS VERSUS ECONOMIC EFFICIENCY

A CBO estimate of the federal cost of royalty reform legislation would provide the Congress with very specific information, such as whether the reform would yield greater profits for lessees, immediate gains in federal royalty collections, and net budgetary savings. But the net economic benefits of royalty reform will ultimately depend on whether those changes result in a more efficient use of the public's natural resources than is now the case. Although such an assessment is beyond the scope of this analysis, the efficiency effects of the reforms under consideration are likely to be small because the production changes that are likely to result are themselves negligible.

5. Senate rules include a point of order relating to the provision of cost estimates for the next 10 years. (In other words, if a bill is not accompanied by a 10-year cost estimate, further consideration of the bill on the Senate floor is prohibited, unless the point of order is waived by vote.)